IGCC Technical Status, Trends and Future Improvements

Neville A. H. Holt – EPRI

Presented at the American Chemical Society Meeting
San Francisco, CA

March 26-31, 2000

Introduction

Coal –based IGCC plants have been developed to commercial size over the past two decades. They have only been built as demonstration plants but are operating as commercial units. These units have now accumulated several years of operating experience and have shown that an IGCC plant can meet extremely stringent air emission standards while also achieving high plant efficiencies. The main barriers to the widespread adoption of IGCC technologies are: (1) demonstration of high availability, at least equal to existing pulverized coal (PC) plants; and (2) capital cost reduction to compete with state-of-the-art PC plants and natural gas–based combined cycles.

Current Status

Three coal-based, commercial-sized (but partially government-funded) IGCC demonstration plant projects are currently operating in the U.S and two in Europe, as summarized in Table 1. The following discussion provides a brief summary of the operational experience to date at these five sites.

Table 1. Coal-Based, Commercial-Size IGCC Plants

Project/Location	Gasification Technology	MW	Startup Date
Wabash River, Indiana, USA	Destec	262	10/95
Tampa Electric Company, Florida, USA	Texaco	250	9/96
Sierra Pacific Piñon Pine, Nevada, USA	KRW fluid bed	100	1/98
SEP/Demkolec, Buggenum, The Netherlands	Shell	253	Early 1994
ELCOGAS, Puertollano, Spain	Krupp-Uhde Prenflo	310	12/97 on coal

The three ongoing US IGCC projects are all based on different gasification technologies and illustrate different application opportunities. All three plants are based on General Electric 'F' gas turbines with turbine inlet temperatures of about 1260°C (2300°F) and equipped with multiple can combustors. The European IGCC projects are both based on Siemens gas turbines equipped with dual silo combustion chambers.

The Piñon Pine and ELCOGAS projects have seen limited operations to date, but both the GE 6FA at Piñon Pine and the Siemens V 94.3 at ELCOGAS have been running very well on natural gas at their design outputs. Although only extended multi-year operations can really test the durability of gas turbines in an IGCC application, the results to date from the projects with the GE F-class gas turbines are very encouraging.

Table 2 presents the major component and overall design performance of these plants, and compares these design values with the operational results achieved to date.

Both the Texaco gasifier at Tampa and the Destec gasifier at Wabash River have demonstrated that they can supply sufficient syngas to fully fuel their combustion turbines. At Tampa, fouling downstream of the gasifier and corrosion in the lower gas temperature range of 250–300°C have been the main causes of outages to date. The developers and plant operators are addressing these problems, but in the meantime the plant continues to perform well, albeit at lower than design efficiency. At Wabash River, the main remaining problem area seems to be the dry gas filter, where corrosion and blinding of the metallic candles continue to occur. The most recent operations at these sites are encouraging and show considerable progress, with both projects experiencing long runs and higher availability.

The SEP/Demkolec (Buggenum) project started operations in early 1994. The tight integration has led to some operational sensitivities and complexities, leading SEP to recommend only partial integration for future installations. This recommendation agrees with EPRI's general analysis of the merits of various degrees of integration, although the optimum performance/operability trade-off depends on the specific characteristics of the gas turbine and its compressor. The ASUs at Wabash and Tampa are supplied by their own compressors, so this problem does not arise.

The main problem encountered in the early years of operation at the Buggenum plant (also later encountered at Puertollano) has been combustion-induced vibrations and overheating in the gas turbine combustors. Design changes made in early 1997 have markedly improved the vibration problem, and since that time several long runs have been conducted, with an availability of over 80% in each quarter since the third quarter of 1997 (with the exception of the second quarters when the required annual inspection is conducted. In the third and fourth quarters of 1998, the Gasification Island was in continuous operation for over 2000 hours. The Shell gasifier has generally performed well and has achieved its design cold gas efficiency.

Table 2. Design and Actual Performance to Date of Major IGCC Projects*

Project	Wabash River	Tampa	Buggenum
Gas Turbine Output, MW	192 (192)	192 (192)	155 (155)
Steam Turbine Output, MW	105 (98)	121 (125)	128 (128)
Auxiliary Power Consumption, MW	35.4 (36)	63 (66)	31 (31)
Net Power Output, MW	261.6 (252)	250 (250)	252 (252)
Net Plant Heat Rate, kJ/kWh LHV Basis	9177 (8708)**	8739 (9244)***	8373 (8373)
Net Plant Efficiency, % LHV Basis	39.2 (41.2)**	41.2 (38.9)***	43.0 (43.0)
1998 IGCC Operating Hours	5139	5328	4939
1998 IGCC On-stream Factor, %	59	61	56
Total IGCC Operating Hours Through December 1998	10,393	10,010	13,768

* Performance is shown as design performance followed by actual to-date performance in parentheses

** Adjusted for HRSG feedwater heaters in service

*** Adjusted for gas/gas heat exchangers in service

The successful scale-up from the 225-tonnes/day gasifier at Houston (SCGP-1 operated 1987–91) to the 2000 tonnes/day unit at Buggenum has been amply demonstrated. The raw gas from a dry-coal-fed gasifier such as Shell has lower water content than the slurry-fed gasifiers of Texaco and Destec. Because of this, dew point corrosion in the lower temperature ranges is less likely to occur and, consequently, has not been a problem at Buggenum.

Both the Wabash River and Buggenum plants have met their overall IGCC design efficiencies. However, Tampa has experienced lower-than-design overall efficiency chiefly due to lower carbon conversion and removal of the gas/gas exchangers from service (to prevent fouling and corrosion).

In summary, these demonstration plants show that IGCC systems can provide power at higher efficiency than PC plants, with significantly lower air emissions and a more benign solid by-product. While the reliability/availability of these units has improved since they were first brought on line, they are not yet operating at commercially acceptable availability levels (only 56–61% in 1998). The developers and government sponsors of these demonstration projects understand this concern and are addressing it through continuing engineering efforts. Based on past experience in the development of new technologies, and assuming continued support by the various government and private parties involved, it is reasonable to expect that the remaining problems will be solved within the next five years.

Market Trends

A number of IGCC plants (many of 500 MW) will be commissioned over the next three years based on the use of petroleum residuals and located adjacent to large petroleum refineries. The shrinking market for high sulfur fuel oil and the impact of tightening fuel specifications and new environmental legislation is the impetus behind these projects. Most of these projects have multiple co-products, typically power, steam and hydrogen for the refinery plus sale of power to the grid or other nearby industrial customers. The projects in Europe are mostly based on heavy oil while the majority of the U.S. projects are based on low value petroleum coke. The experience gained from these projects should aid in reducing the capital cost of IGCC equipment and in providing greater confidence in the reliable operation of this technology.

IGCC plants can meet extremely strict environmental and emission standards and may be applicable to particular locations that have such requirements. If emissions including CO_2 were ever subject to externality charges or taxes this would make IGCC a more attractive technology. Several studies have shown that if CO_2 removal from fossil- based power plants is ever required for subsequent disposal, use or sequestration, that it would be much less costly to remove the CO_2 from syngas under pressure prior to combustion rather than removal from the huge volumes of stack gases after combustion at atmospheric pressure. The absorption process is driven by partial pressure and the size of vessels is much reduced under pressure.

Table 3. IGCC Plants based on Petroleum Residuals

Project/Location	Feedstock	Gasification Technology	MW /Steam/ Hydrogen	Startup Date
Shell- Pernis, Netherlands	Visbreaker tar	Shell	127/ Steam/H2	1/98
ISAB/Mission –Sicily,Italy	Asphalt	Texaco	500/Steam/H2	9/99
API/ABB/Texaco –Falconara, Italy	Visbroken Vacuum residue	Texaco	250/Steam	3/2000
SARAS/Enron	Heavy oils	Texaco	550/Steam	3/2000
Motiva/Texaco	Petroleum Coke	Texaco	200/Steam	3/2000
Total/EDF/Texaco- Normandy, France	Heavy oils	Texaco	365/Steam/H2	2003
Repsol/Iberdrola/Texaco –	Heavy oils	Texaco	7-800/Steam/H2	2003
Bilbao, Spain				
Exxon Singapore	Ethylene cracker bottoms	Texaco	160/CO + H2	2002

Future Technical Improvements

The larger higher efficiency G and H gas turbines, with firing temperatures of ~1500°C (2732°F) are now entering commercial service based on natural gas. When applied to IGCC plants these turbines will provide further gains in efficiency and reductions in capital cost through economy of scale. The U.S. DOE through its Vision 21 initiative has a comprehensive R&D program with gasification as a key core technology. Improvements in all aspects of the basic IGCC flowsheet are being addressed including ion transport membranes for improved ASU's, more flexible fluid bed gasifiers, high temperature gas clean up for particulate and sulfur species removal, high temperature membranes for separation of hydrogen and CO_2, advanced gas turbines and cycles. This program should result in a stream of new developments improving the performance and reducing the capital cost of IGCC plants.